2016

James Harvey Jordan, Et Al. v. Eddie R. Jensen and Ly-Thi Jensen : Brief of Utah Farm Bureau, Utah Petroleum Association, Utah Mining Association and Utah Taxpayers Association as Amici Curiae on Behalf of Appellees

Utah Supreme Court

[redacted]

IN THE UTAH SUPREME COURT

JAMES HARVEY JORDAN, ET AL.,

Appellees,

vs.

EDDIE R. JENSEN AND LY-THI JENSEN,

Appellants.

EDDIE R. JENSEN AND LY-THI JENSEN,

Appellants.

v.

JAMES HARVEY JORDAN, MARTHA JORDAN BORIGHT; MARY EDNA JORDAN; AXIA ENERGY, LLC; AND STONEGATE RESOURCES, LLC,

Appellees.

Appeal No. 20150257-SC

BRIEF OF UTAH FARM BUREAU, UTAH PETROLEUM ASSOCIATION, UTAH MINING ASSOCIATION AND UTAH TAXPAYERS ASSOCIATION AS *AMICI CURIAE* ON BEHALF OF APPELLEES

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IN THE UTAH SUPREME COURT

JAMES HARVEY JORDAN, ET AL., Appellees, vs. EDDIE R. JENSEN AND LY-THI JENSEN, Appellants.	Appeal No. 20150257-SC
EDDIE R. JENSEN AND LY-THI JENSEN, Appellants. v. JAMES HARVEY JORDAN, MARTHA JORDAN BORIGHT; MARY EDNA JORDAN; AXIA ENERGY, LLC; AND STONEGATE RESOURCES, LLC, Appellees.	

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SUMMARY OF ARGUMENT

The Utah Petroleum Association, Utah Mining Association, Utah Taxpayers Association, and Utah Farm Bureau (collectively "Associations"), by and through counsel of record, hereby jointly file this amici curiae brief in the above captioned matter to request the Court to avoid placing precedential language into an opinion that would require either the Utah State Tax Commission (hereinafter "Tax Commission" or "Commission") or the counties to uniformly find and value undeveloped mineral reserves for purposes of applying a property tax.

Pursuant to Rule 24(i) of the Utah Rules of Appellate Procedure, the Associations have reviewed and adopt the arguments raised in the amicus brief filed by the Utah State Tax Commission ("Commission Amicus Brief") – including the arguments that (1) the Utah Constitution and statutes prohibit the taxation of undeveloped mineral reserves, and (2) property taxes have not historically been imposed on undeveloped mineral reserves in Utah. In the instant brief, the Associations raise additional arguments specific to Association members that were not raised by the Tax Commission as follows:

1. Authority to assess all minerals is limited to the Tax Commission under case law, and both the uniform and equal provision and the fair market value provision of the Utah Constitution, thus precluding county assessment of any minerals.

2. Public policy implications militate against assessing and taxing undeveloped reserves because such would either lead to forfeiture of undeveloped mineral reserves by owners unable to immediately develop them or force premature

development of some mineral reserves in potentially unfavorable market conditions. Further, the assessment of undeveloped mineral reserves is by its nature very imprecise, speculative and changing, potentially infringing upon the uniformity requirement of the Utah Constitution.

3. Any change in assessment practices of undeveloped minerals would first require a constitutional amendment and appropriations by the Utah Legislature.

ARGUMENT

I. THE TAX COMMISSION IS THE SOLE ENTITY IN UTAH WITH AUTHORITY TO ASSESS MINERAL RESERVES FOR PURPOSES OF APPLYING A PROPERTY TAX AND IT MAINTAINS THAT AUTHORITY EVEN IF NO TAX IS IMPOSED FOR LACK OF VALUE OR UNIFORMITY.

The Associations have reviewed and agree with all of the Commission Amicus Brief, including section I.B. In section I.B., the Tax Commission notes that "if a mineral reserve is to be taxed directly, it can only be assessed by the Commission, and if a mineral reserve is undeveloped, it is not directly taxable by any entity." The Commission then adds legal support for this principle by citing to the Tax Commission's constitutional authority under Art. XIII, section 6 to "assess mines," and to Utah Code section 59-2-102(24), (27) which defines mines. The Associations agree that this legal authority supports the stated principle, and also hereby provide the Court with additional legal support for this principle.

In *Kennecott Corp. v. Salt Lake County*, 702 P.2d 451, 457 (Utah 1985), the Utah Supreme Court held that only the Tax Commission can assess mines. The Court held that because the Utah Constitution provides that only the Tax Commission can assess mines, "the Legislature is without power to confer the power of assessing mines . . . on . . . the district courts." Like the Legislature and courts, counties similarly have no constitutional authority to assess or tax mines.

There is also additional legal support for the principle that "if a mineral reserve is to be taxed directly, it can only be assessed by the Commission, and if a mineral reserve is undeveloped, it is not directly taxable by any entity." *See* Commission Amicus Brief, at section I.B. This support is found in Utah Constitution Article XIII, section 2(1), which provides that "all tangible property in the State . . . shall be . . . assessed at a uniform and equal rate in proportion to its fair market value." (Emphasis added). Insofar as a mineral reserve does not have value, it is not taxable, and insofar as it does have value it can only be assessed by the Tax Commission. Thus, pursuant to Article XIII, section 2(1) of the Utah Constitution, counties are precluded from taxing undeveloped reserves because property without identifiable market value is not taxable by either the Commission or the counties.

Moreover, where this fair market value clause and/or the uniform and equal clause (also in Art XIII, § 2(1)) preclude the assessment and taxation of undeveloped mineral reserves, as is the case here, this does not mean the Tax Commission loses and the counties gain the authority to assess and tax undeveloped mineral reserves. Undeveloped mineral reserves with unknown quantity or quality still fall under the Tax Commission jurisdiction for assessment under Article XIII, section 6 of the Utah Constitution, even though the Commission does not assess them.

II. TAXING UNDEVELOPED RESERVES WOULD CREATE POOR PUBLIC POLICY.

Assessing and taxing undeveloped reserves would create poor public policy. Much of the privately held land with undeveloped reserves is owned by farmers and ranchers who would likely have no cash flow with which to pay the property tax on reserves that are sitting idly in the ground. Constitutional requirements of uniformity would mandate that these property owners pay taxes on undeveloped reserves, forcing some to sever their mineral rights at a great discount due to the uncertainty, sell their entire property, enter into unfavorable leases, or lose their property as a result of inability to pay taxes assessed on the undeveloped mineral reserves.

Further, imposing a tax on undeveloped reserves may well drive many mineral producers from the state or incentivize them to act contrary to the market. Mineral producers who hold property for future development are not likely to continue to hold undeveloped mineral interests if they are forced to pay a tax bill with no income to offset the taxes. In addition, owners of undeveloped mineral interests may choose to accelerate production or mining efforts to generate income to pay taxes (rather than lose their property at a tax sale) and will find themselves at odds with market cycles, as well as environmental, agricultural, and other community interests. Also, if the producers release their leasehold interests, the individual landowners will then bear the burden of paying taxes on mineral property even though they do not have the means to extract the minerals nor related income stream to pay the taxes.

Imposing a tax on undeveloped reserves would also place a tremendous burden on the Tax Commission and the taxpayers of Utah, with little to no potential benefit, as few if any undeveloped reserves have value. Utah has maintained a wise historical course by not taxing undeveloped reserves. This historical practice should continue.

To try to tax all undeveloped reserves on a uniform basis is impractical because constitutional and statutory mandates would require the Commission to find and uniformly value all of the copper, oil, gas, salt, etc. under the land of every farmer, rancher, and other landowner in Utah. *See* Utah Constitution Article XIII, section 2(1). This would place a substantial burden on the farmers, ranchers, mining companies and oil and gas companies in Utah, and is simply not feasible, for several reasons.

First, the Tax Commission would have to hire engineers, geologists and geophysicists to try to find the minerals and make the necessary valuation determinations. Even then, determining value would be a speculative guessing game, if there was any value at all. Reserves are generally undeveloped precisely because, under current circumstances, it is not economical to develop those reserves. *See* Commission Amicus Brief, at section I.A.

Second, oil and gas are "fugitive resources" which often migrate, grow and/or shrink. Oil and gas "have no fixed situs under a particular portion of the earth's surface within the area where they obtain." *Ohio Oil Co. v. Indiana*, 177 U.S. 90, 202 (1900). "They have the power, as it were, of self-transmission." *Id.* It is impractical to uniformly value undeveloped oil and gas reserves that often move and change.

Third, until drilling occurs, the quality of the oil or gas cannot be ascertained – whether sweet or sour. Sweet oil or gas can be sold directly from the wellhead, whereas sour oil or gas requires extensive treatment before it can be sold and may have no value in its natural state. *See Union Oil Co. v. Utah State Tax Comm'n*, 2009 UT 78 ¶¶ 4, 5, and 10, 222 P.3d 1158, 1160-61. It is impractical to uniformly assess a value to a product of unknown quality.

Fourth, estimates and values of reserves are uncertain and are impacted by changes in technology, regulation, conservation efforts, and fluctuating prices. Improvement to hydraulic fracturing methods combined with horizontal drilling have opened up new reserves of oil and gas in shale formations. Exhibit A (*see* heading titled "Hydraulic Fracturing"). New York State's ban on hydraulic fracturing in the state of New York, although not affecting Utah, is an example of how regulation severely diminishes the recoverability oil and gas reserves. *See* Exhibit B. Further, conservation efforts impact resource recovery as demonstrated by a proposal introduced in 2014 which would set aside nearly 83,000 acres in Utah and Colorado to protect a pair of rare flowering plants found only on lands overlaying oil shale formations in Utah and Colorado, changing the economics of oil production. Exhibit C. Finally, huge fluctuations in oil, gas and other mineral prices affect the value of the reserves and determine whether companies will attempt to remove minerals from the earth. Exhibit D ("Sharp declines in new production are evident in high-cost plays, while growth in some low-cost unconventional production appears virtually unaffected.").

For all of these reasons, it is simply not feasible for the Tax Commission to try to uniformly find and value all undeveloped reserves consistent with the requirements of the Utah Constitution and statutes.

III. ANY TAX ON UNDEVELOPED RESERVES SHOULD BE IMPOSED THROUGH A CONSTITUTIONAL AMENDMENT AND/OR LEGISLATION.

Undeveloped reserves have not historically been taxed in Utah and, if they are to be taxed, it should be done through (1) a constitutional amendment which removes the uniformity clause, or (2) legislation whereby the legislature can appropriate funds to the Tax Commission to hire the geologists and engineers necessary to uniformly locate and value all undeveloped reserves in the state. An enormous undertaking would be required to value the entire state's undeveloped mineral reserves. Many budget and appropriations actions and policies would be required. The people of Utah and, thereafter, the Legislature should thus change the policy if it is to be changed.

CONCLUSION

The issue of whether undeveloped mineral reserves are taxable is important to the Associations and has significant ramifications. The Associations thus respectfully request that this Court avoid putting any precedential language in its opinion that would suggest that undeveloped reserves are taxable under the law, or would otherwise require the Tax Commission as a matter of law to start uniformly locating and valuing all undeveloped reserves.

DATED this 8th day of February, 2016.

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CERTIFICATE OF COMPLIANCE.

This brief complies with type-volume requirements of Utah R. App. P. 24(f)(1). This brief contains 1,801 words, exclusive of the Cover, Table of Contents, Table of Authorities and Addendum, according to the word count of the utilized word processing system.

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing BRIEF OF UTAH FARM BUREAU, UTAH PETROLEUM ASSOCIATION, UTAH MINING ASSOCIATION AND UTAH TAXPAYERS ASSOCIATION AS *AMICI CURIAE* ON BEHALF OF APPELLEES was served this 8th day of February, 2016, in the following manner upon the addressees listed below:

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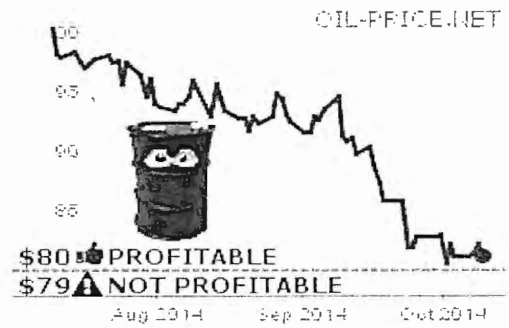
Tab A



High-tech US oil producers need $80 per barrel to be profitable. Saudis need only $50.

Oil Price Fall Threatens US Oil Production

By STEVE AUSTIN for OIL-PRICE.NET, 2014/11/04

A falling oil price is good for the US consumer and good for the US economy. Transport costs feed into the price of every physical product, so if oil gets cheaper, everything gets cheaper. If the oil price falls too far, however, the USA's recent fracking boom will come to an end. Forces are at play to end the USA's projected energy independence and return the country to dependence on the Middle East for its fuel supplies. The USA's long-term key supplier, Saudi Arabia, doesn't want to lose grip on its best customer.

Recession

Falling factory output in China and the onset of recession in Europe means that a continued fall in the demand for crude oil is inevitable. The recent return to production of Algeria, Libya, Iraq and Iran means that the world is already oversupplied with crude oil. The astonishing rise of production by hydraulic fracturing in the USA means that America is increasingly self-sufficient in oil. When supply exceeds demand a fall in the price of any product is inevitable.

When a market is over supplied, prices continue falling until enough suppliers are forced into bankruptcy to reduce supply to the level of demand. At that point, prices can start to rise again. This is the classic explanation of the causes of recession and recovery. However, the oil market is different. Lead times and start up costs are high in the industry and so production cannot just be turned on and turned off at will. Oil has a global sales price but location-dependent variations in production costs. Middle eastern producers responded to the peculiarities of the oil economic cycle by forming OPEC to limit supply in times of economic decline and support the price of oil. By controlling supply levels and sharing out the cuts between them, the 12 nation club can ensure that none of the producers have to go bust before supply and demand return to equilibrium.

Return to Market

The recent return of production by Algeria and Libya put pressure on OPEC's oil quotas. Both these recovering countries are OPEC members and so their sudden return to the market means that the club now exceeds its self imposed limit of 30 million barrels per day. The inevitable fall in the price of crude oil, caused by over supply, should have sent the members to the conference table for an emergency quota-slashing meeting. However, key members of OPEC fell silent, and stuck to the planned meeting schedule, meaning the group will not meet until November to talk about limiting output.

OPEC has no power to impose its quotas and so if the member states do not want to abide by them, there is little anyone can do about it. The group's stated limit of 30 million barrels per day would still see the market in over supply. Any quota-busting production spells disaster for the price of crude oil.

Policy Change

Saudi Arabia is by far the largest producer in OPEC, although on a global scale, their output is exceeded by Russia. It has always been in Saudi Arabia's interests to keep the price of oil high. This is because, despite decades of wealth, the county hasn't managed to produce any other industry that could sustain the levels of state spending to which the country has grown accustomed. Saudi Arabia uses the threat of reduced production and high oil prices to give it a very power voice in world politics and it is particularly adept at co-opting American military might to its pet causes.

Suddenly, Saudi Arabia seems to have switched its policy. It increased its production in September 2014 and not only fails to support the current price but seems to be actively pricing its sales to drag the global price of oil down. The country is now selling at a price lower than the level it needs to maintain state spending. It is dipping into reserves to enable it to undercut its rivals. The OPEC alliance has split and old rivalries in the Middle East are driving the current fall in oil prices.

Hydraulic Fracturing

The techniques behind hydraulic fracturing have been around since the 1930s. However, refinement of the process and its application to shale in the late 1990s made the process a commercially viable method of oil extraction. As the technique developed and was combined with horizontal extraction methods, hydraulic fracturing, or "fracking" created exponential growth in US oil production. By 2010, the success of fracking had removed the need for the USA to import gas and US companies skilled in the technique began to spread across the world looking for earning opportunities in other countries. Large shale oil basins were discovered across the globe and US businesses looked set to reap the rewards of their expertise by dominating oil production by this technique.

Oil Price

In a perfect market, unhindered by politics, cartels or special interests, the price of a product is the only mediator between its demand and its supply. When demand for oil exceeds supply, its price rises, making extraction from inhospitable locations, like the Arctic tundra or offshore platforms, economically viable. More of the world's oil becomes profitable and so more is extract by extending production to previously unprofitable locations. Output rises to meet demand and the price stabilizes. If supply exceeds demand then the price falls. If the price falls far enough, and stays low long enough for those extractors in high-cost locations to go bust, excess production will be squeezed out of the market and the price will rise again.

The expansion of fracking in the United States has contributed to over-supply. Fracking is only viable at a certain oil price level, so, in many ways, by forcing over-production, hydraulic fracturing oil producers have contributed to their own problems. Investments were made in low-margin extraction and loans were secured to finance them, based on the convention that no matter how much oil the US produced, price levels would be maintained by OPEC cutting production. Financiers did not have to worry about the dangers of supply and demand because OPEC would ensure price stability.

New Normal

Saudi Arabia has put its foot down. In the face of triumphalist crowing about energy independence in North America the country has turned to the classic economic model of price being determined by the equilibrium between supply and demand. Not only are they not reducing their prices, they are actually cutting them. They are not lowering production levels, they are increasing them. The Kingdom has large cash reserves and they seem to be prepared to coast on their savings for as long as it takes for their competitors to go out of business. Fracking is vulnerable and will not survive a price drop unless the US oil industry reorganizes.

Challenges

Thanks to financing costs, new hydraulic fracturing sites are unlikely to be opened up if oil stays at less than $90 per barrel for any length of time. Each extraction project is different and incurs different plant investment costs, returning different profit margins. The banking industry, however, works on a blanket level of a need for $80 per barrel for a project to turn a profit. The extra $10 is needed to ensure the banks get paid back.

However, some shale oil regions, such as the Eagle Ford Shale and Permian Basin in Texas can still turn a profit selling at $53 per barrel. The problems faced when assessing any new shale oil project include distance to distribution points, local availability of accommodation, the capacity of the transport network and availability and price of expertise and staff. These factors can make crude oil cheaper to deliver from Texas or North Dakota to refineries on the East Coast, or it can make Saudi oil, arriving by tanker, cheaper than domestically produced oil.

Solution

Hydraulic fracturing became a viable business in the US because of a rising oil price and also because of falling production costs. Necessity is the mother of invention and it should not be assumed that the industry will not continue to develop cheaper methods and equipment. The shale oil producers have been living high on the hog with a gold rush mentality, spraying cash in all the communities into which they move. Therefore, there is a lot of fat to trim to bring inception and operation costs down. High payments to property owners for drilling access are probably soon to be dramatically reduced, building schools and community facilities are expensive public relations exercise that may not happen again.

Supported by technology and aggressive cost cutting, the US shale extraction oil producers can continue to expand their share of the market. Pipeline projects to distribute domestic oil to US refineries would lower delivery costs and further reduce the price disadvantages of shale oil. US producers need to be smart and act quickly, however, the Saudi Arabia Oil Policies and

Strategic Expectations Center recently revealed that the Kingdom is prepared to go as low as $50 per barrel, which would be a tough price to match.

Tab B

BloombergBusiness

N.Y. Officially Bans Fracking With Release of Seven-Year Study

Freeman Klopott
June 29, 2015 — 1:16 PM MDT
New York state has officially banned hydraulic fracturing.

The state, following through on a decision Democratic Governor Andrew Cuomo made in December, released its formal study of the drilling practice Monday after almost seven years of study. The report, which drew the same conclusions as a shorter version released Dec. 17, said studies on fracking's effects on water, air and soil are inconsistent, incomplete and raise too many red flags.

"After years of exhaustive research and examination of the science and facts, prohibiting high-volume hydraulic fracturing is the only reasonable alternative," Joe Martens, commissioner of the Environmental Conservation Department, said in a statement.

Parts of New York sit atop the gas-rich Marcellus shale formation, and Cuomo had been trying to balance the prospects for the economic development seen in Ohio and Pennsylvania against environmentalists' warnings that fracking might taint water and make farmland unusable.

The balancing act ended in December with Cuomo's decision to follow the advice of the health department and ban the practice. The move was hailed by environmentalists and derided in the economically depressed Southern Tier region.

Tab C

Deseret News

Protections for flowering Uinta Basin plants will cost $3 million

May 6, 2014

SALT LAKE CITY — A federal proposal to set aside nearly 83,000 acres in Utah and Colorado to protect a pair of rare flowering plants will cost nearly $3 million in a single year, mostly to traditional oil and gas producers.

The U.S. Fish and Wildlife Service released a draft economic analysis on the impacts of designating critical habitat for the Graham's beardtongue and White River beardtongue, which are only found in the oil shale formation in Utah and Colorado.

A draft conservation proposal, which drew sharp criticism from the Southern Utah Wilderness Alliance, is being pursued as a possibility because the agency said the plants would not receive the benefit of voluntary protections already in place under an Endangered Species Act listing.

"Under the ESA, plants do not receive protection on private lands unless there is a federal nexus," the agency said. "Therefore, the service is engaging private landowners in voluntary efforts for these two species. This is especially important for the White River beardtongue since almost half of its distribution occurs on private lands."

The Graham's beardtongue in Duchesne and Uintah counties would receive protections under a proposal by the U.S. Fish and Wildlife Service to set up critical habitat and implement "pollination" zones. It would cost energy developers nearly $3 million in the first year, should the restrictions go into place. (Kevin Megown, U.S. Fish and Wildlife Service)

A public hearing will be held in Vernal May 28 at the Uintah County Library on the proposed protections for Uintah and Duchesne counties in Utah, and Rio Blanco County in Colorado.

"From our end, the (plants) are threatened on all sides by encroaching oil and gas and now oil shale development," said Steve Bloch, attorney with the Southern Utah Wilderness Alliance. "This is just the latest of missteps by the U.S. Fish and Wildlife Service. We are hugely disappointed that the Fish and Wildlife Service after 10 years of dithering is working against the betterment of this species."

According to the proposal, Graham's beardtongue, which sports vivid pink flowers, would be protected on 67,959 acres that would include "pollinator" zones to ensure its continued survival.

The plant grows only in a 80-mile horseshoe bend on oil shale strata. Oil shale development, the agency estimates, would impact 82 percent of the plant's population, while all energy development poses a risk to 91 percent of the plants, according to a draft environmental analysis.

Photograph of White River beardtongue. A draft study on the economic impacts of federal protection zones for a pair of flowering plants found in the Uinta Basin puts costs to traditional energy development at nearly $3 million in the first year. A public hearing is set in Vernal May 28. (U.S. Fish and Wildlife Services)

For the White River beardtongue, the service is proposing 14,940 acres of land to be set aside for protections. Energy development, the service estimates, would impact 100 percent of the plant.

Energy development, the service contends, would "likely lead to severe declines," in both species if protective action isn't taken.

The analysis estimates the bulk of the costs that would come from the establishment of protection zones would be borne by traditional oil and gas producers — $2.7 million in the first year. Costs to grazing would be $9,000.

A potential oil shale project that would overlap with federal lands would incur costs estimated at $130,000, according to the federal analysis.

The study notes that a "substantial" portion of the proposed critical habitat for the plant falls within federal lease areas in Utah and Colorado for oil shale and tar sands. For the Graham's beardtongue, 66 percent of its population is on Bureau of Land Management acreage, while 39 percent of the White River beardtongue grows on BLM land.

Kathleen Sgamma, vice president of governmental affairs for the Western Energy Alliance, said the federal government is proposing an action that is unwarranted using an analysis that greatly downplays the economic ramifications.

"This is a good example of how the Endangered Species Act is being used to stop energy development as opposed to really protecting an endangered species."

Sgamma said the U.S. Fish and Wildlife Service has wrongly taken an overall species of plant that widely occurs throughout the area and segregated it into two subgroups to make a case for federal protections.

Tab D

center for
ENERGY
STUDIES
Rice University's Baker Institute for Public Policy

EFFECTS OF LOW OIL PRICES ON U.S. SHALE PRODUCTION: OPEC CALLS THE TUNE AND SHALE SWINGS

BY JIM KRANE, PH.D., AND MARK AGERTON

FEBRUARY 2015

Effects of Low Oil Prices on U.S. Shale Production: OPEC Calls the Tune and Shale Swings

Jim Krane, Ph.D., Wallace S. Wilson Fellow for Energy Studies
Mark Agerton, Graduate Fellow for Energy Studies and Ph.D. student, Department of Economics

Introduction

Emerging data on U.S. oil drilling and output show that U.S. shale producers appear to be among the first to respond to the collapse in global crude oil prices. Sharp declines in new production are evident in high-cost plays, while growth in some low-cost unconventional production appears virtually unaffected.

Oil prices shed around half of their value between June and December 2014, falling precipitously after OPEC's November decision to maintain constant oil production. Saudi oil minister Ali al-Naimi declared that OPEC would defend its share of global crude oil markets from upstart producers, including U.S. shale operators. Two months later, OPEC's actions appear to be generating the desired effect. New oil production in some U.S. shale plays appears to have been curtailed, especially since November. Signs include shrinking numbers of drilling rigs in operation, fewer wells being drilled, and reductions in the volumes of new oil production coming onstream.

The clearest evidence of decline has emerged from the Permian Basin of Texas and New Mexico. There were steep drop-offs in the number of rigs in operation and in the drilling of vertical wells. As a result, projected new oil flow, especially from vertically drilled wells, has decreased.

The picture is far from universal, however, and important counter-cases bear mention. Perhaps the most contrarian is South Texas' Eagle Ford shale, where data from the Austin-based analytics firm Drillinginfo show rising numbers of wells drilled and increasing volumes of oil produced, even between the months of November 2014 and January 2015, as bad news spread across the global oil sector.

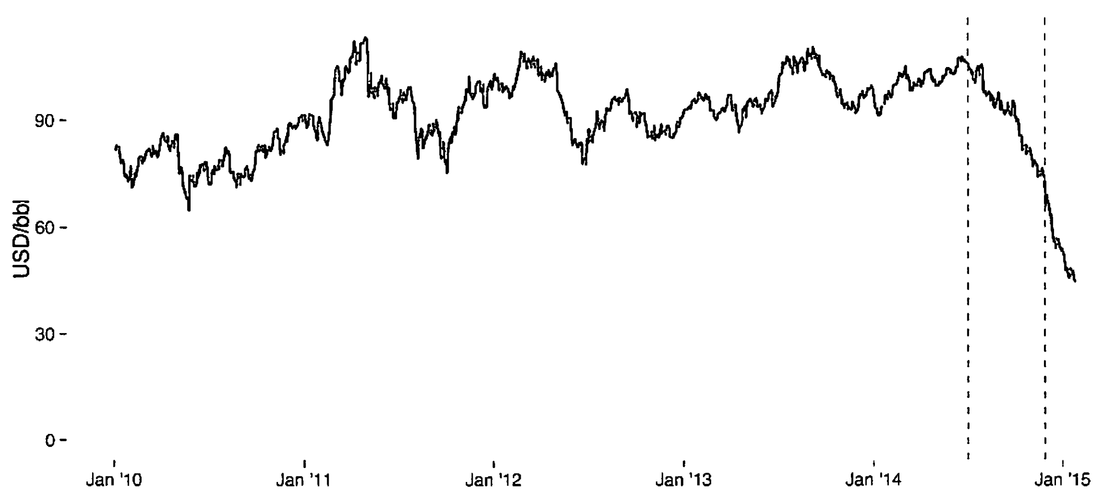
It bears emphasizing that the slowdown in growth, where it applies, does not mean that overall U.S. oil production has decreased. It means that production growth is occurring at a decreasing rate.

Significance

The Drillinginfo data appear to confirm speculation that some of the first reductions in worldwide oil production would take place in the U.S. shale sector. The shale industry is now revealing itself as a nimble and price-responsive producer at a time when OPEC member-states have refused to squelch their own production, thereby rejecting their customary market-balancing role. The International Energy Agency (IEA) expects other high-cost producers such as Canada and Colombia to join in the cuts in production, but investment momentum and price hedging often mean that oil output continues to rise in the near term.[1] The U.S. Energy Information Administration (EIA) forecasts that overall U.S. oil production will increase until the third quarter of 2015 for similar reasons.[2] Long-planned conventional projects, including those offshore, continue to bring new production online.

A number of analysts predicted that market dynamics would force shale producers to assume a portion of the swing producer role formerly held by Saudi Arabia.[3] As is now well known, OPEC members announced at their Nov. 27 meeting that member-states would maintain a constant level of production, refusing to reduce oil flowing to an oversupplied global market. The drop in oil prices accelerated immediately after Nov. 27 (see Figure 1).

Figure 1. West Texas Intermediate spot price



Source: Energy Information Administration
July 1 and Nov 27 indicated by dashed lines

Al-Naimi blamed rising non-OPEC production for OPEC's divergence from past practices, arguing that any OPEC cut would be quickly annulled by production increases from emerging competitors.

"Why did we decide not to reduce production? I will tell you why," al-Naimi said in December. "If I reduce, what happens to my market share? The price will go up and the Russians, the Brazilians, U.S. shale oil producers will take my share."[4]

To date, however, there has been little quantitative evidence of a non-OPEC supply response. Anecdotal reports have described declining investment, job cuts, and dropping numbers of drilling rigs in operation. Missing from these reports were figures detailing numbers of actual wells drilled, whether levels of new oil production had declined, and, if so, which basins bore the brunt of those declines. This paper intends to bridge that gap by leveraging previously unreleased data provided by Drillinginfo that sheds light on these important shortcomings.

The Drillinginfo index reveals reduced investment in some shale formations—both in terms of number of wells and the overall production potential of these investments—and opposite effects in others. What emerges is an illustration of the diverging fortunes of an industry that appears to be shifting into a low-price mode in which retrenching firms set aside drilling plans in less-productive zones and focus efforts on their most productive acreage and highest efficiency extraction techniques. These revelations portend a new paradigm in an industry where decades-long investment horizons have typically led to over- or under-shooting market needs, contributing to price volatility.

The enhanced price-responsiveness of shale extends from a key difference with conventional oil exploration and production, in which shale resembles a manufacturing process. Exploration is generally unnecessary because locations of oil-rich shale basins are already known. However, constant levels of production require constant rates of well drilling, due to steep decline curves on well productivity. If drilling declines, production tends to follow.

Methodology

We combined two primary sources of data to tell this story. First, we were given access to previously unreleased monthly data from Drillinginfo, a company that compiles diverse ground-level data on oil and gas production. Second, we examined those data alongside rig count data from Baker Hughes, which has been a standard data source for analysts tracking industry investment trends.

The Drillinginfo index tracks new onshore wells that have been drilled ("spudded") across most of the lower 48 U.S. states since March 1, 2014.[5] The index assigns each well a predicted peak production volume, which is calculated as the average peak production of nearby wells of a similar type. The index is computed on a monthly basis, and wells are tracked down to precise latitude and longitudes. Thus, the index provides an indication of the level of investment and drilling activity at a precise geographical location, as well as a useful estimate of expected initial production. These data are provided for the previous calendar month, a shorter time frame than those of other public reports.

It is important to interpret the Drillinginfo production index carefully. The index estimates the maximum monthly new oil production likely to flow from a given well drilled in a given month. The data do not show when or whether the wells are completed or connected to gathering infrastructure. Peak production normally occurs at least a month after the well and its production are counted in the index. Further, new production covered in the index is a fraction of overall U.S. oil production. The index captures a future marginal increase in total production from new wells. Thus, even if the index showed zero new production for January, production could still continue to rise as wells drilled earlier in the year come online.

Our second data source, the rig count data from Baker Hughes, details the number of rigs "actively exploring for or developing oil or natural gas" on a weekly basis in each U.S. county. The dataset tags each rig as horizontal or vertical (an indicator of whether the well is unconventional or conventional) as well as whether the well is targeting oil or natural gas. The data are similar to the DI Index in that they provide an indicator of the level of new upstream investment.

Rig counts fail to capture productivity differences in terms of number of wells drilled or expected volumes of production from those wells. However, the Baker Hughes rig count is available for a longer time horizon (since early 2011). Changes in the rate of upstream investment will appear sooner in Baker Hughes' weekly rig counts than in the monthly Drillinginfo index.

Five Places Where Production is Dropping

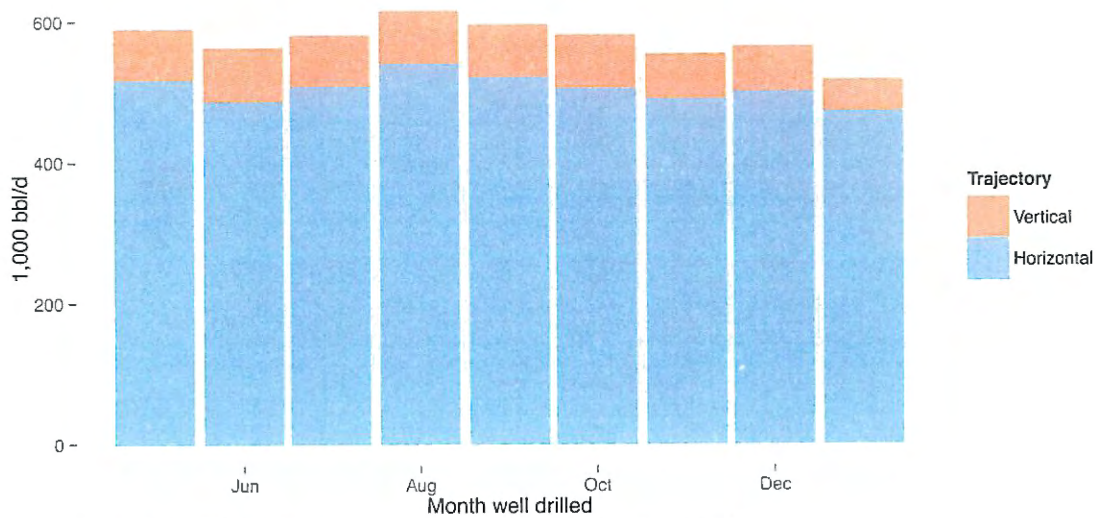
National

Across the continental United States, data from Drillinginfo show a gradual 13% decline in new oil production brought onstream in a given month, from about 600,000 barrels per day (bbl/d) in May 2014 to just under 525,000 bbl/d in January 2015. Although new production rises and falls throughout the period, it appears significant that levels in January—after falling oil prices became a concern—are the lowest of any of the months shown.

New oil-directed[6] well starts showed greater declines, dropping by 32%, from 1,967 in May to 1,338 in January. Oil drilling dropped by the largest amount, 24%, between December and January, as oil prices hit their lowest levels.

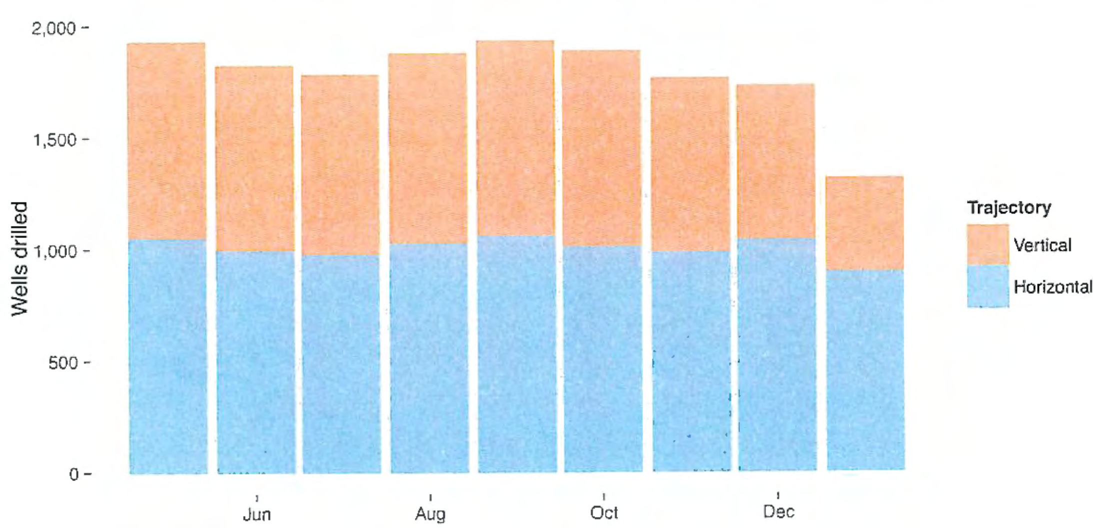
Geographically, the biggest declines appear to be affecting North Dakota's Bakken formation, while in technological terms, the largest declines concerned vertically drilled wells.

Figure 2. New U.S. liquids production from all wells drilled in the month indicated, by well trajectory



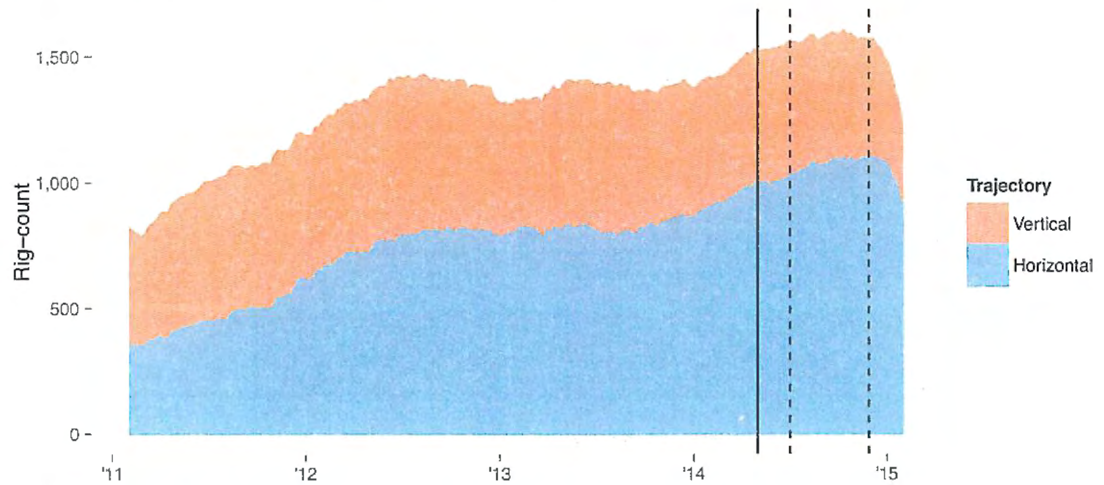
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 3. New U.S. oil wells drilled in the month indicated, by well trajectory



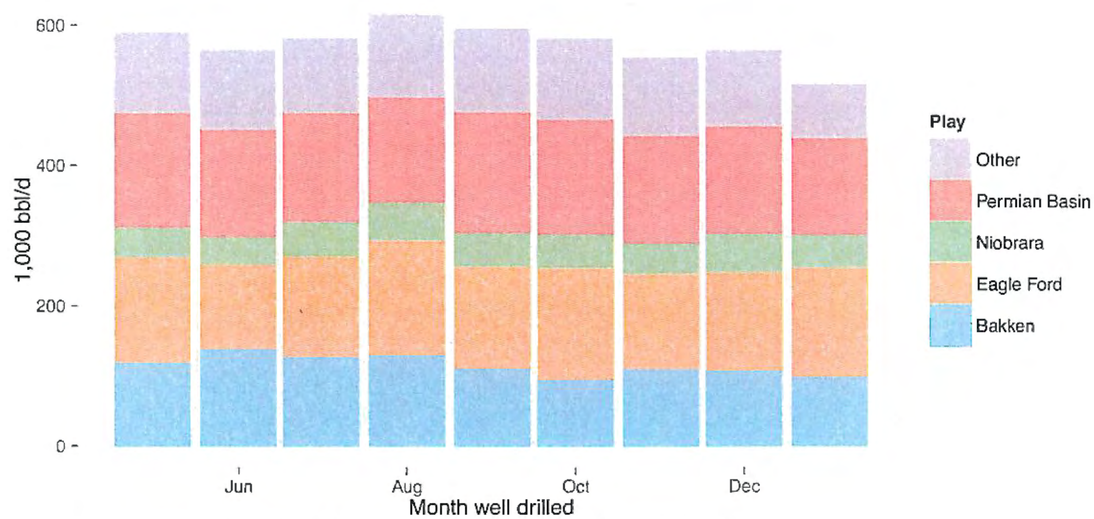
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 4. Active oil-directed rigs in the month indicated, by well trajectory



Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Figure 5. New U.S. liquids production from wells drilled in the month indicated, by formation



Source: Drillinginfo; Scaled to compensate for number of days in month.

Permian Basin

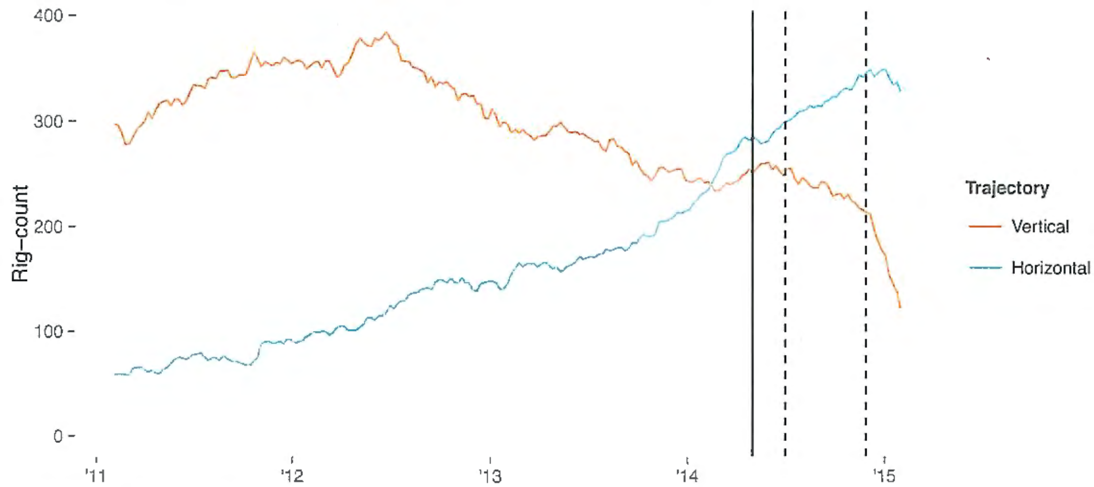
Among the major U.S. oil formations, the clearest signs of price-influenced changes in production are seen in the Permian Basin, where, after evidence of a long surge in investment and vertical and horizontal drilling since 2011, new production was down by almost 16% between May 2014 and the end of January 2015. However, the decline in predicted peak production appears to be tied mainly to a reduced number of vertical wells. New production from vertical wells plummeted by 46%, from 36,000 bbl/d in May 2014 to just under 20,000 bbl/d in January 2015. The steepest fall-off coincides with the OPEC announcement in late November. Predicted production of about 30,000 bbl/d in December tumbled by 36% to just under 20,000 bbl/d in January. Many of these vertical wells are in the eastern Permian's Midland Basin where production is linked to vertical "infill" wells drilled in mature fields. Vertical infill wells are relatively simple and inexpensive to drill, which allows producers to pull back production when prices drop.

For horizontal wells in the Permian, which are more heavily concentrated in its western Delaware Basin, the case is different. Drillinginfo data show predicted new production remaining relatively constant from May through January at roughly 125,500 bbl/d. In fact, there was virtually no change in new production from horizontal wells between November—prior to the oil sector lapsing into panic mode—and January, well after that period was underway.

Another strong indicator of producers reacting to falling oil prices came in the form of a sharp increase in the average productivity of horizontal wells in the Permian, which jumped by 11%, from an average of 458 bbl/d per well in December to 507 bbl/d in January. Rising well productivity conforms to expectations that firms would shift away from low-producing wells in non-core areas and concentrate on drilling horizontal wells in their most productive acreage. The Drillinginfo data appear to bear out these predictions.

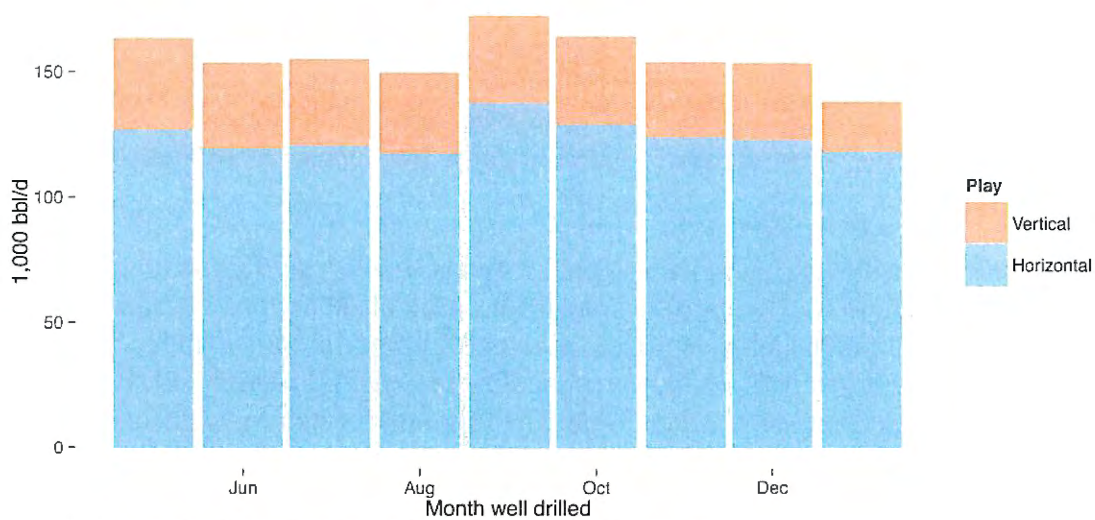
Finally, the Baker Hughes rig count data corroborates these findings. Rigs drilling oil-directed vertical wells in the Permian declined from a peak of 385 in June 2012—well before the current slump in global oil prices—to a low of 122 at the end of January 2015. Figure 6 below shows a steep rig decline after the November OPEC meeting, illustrated by the vertical dotted line on the right-hand side. The rig count for horizontal drillers also shows a decline, albeit a smaller one. After reaching a peak of 349 on December 5 (where it stayed until January 2), rig counts fall to 328 by the end of January 2015.

Figure 6. Rig-count in Permian Basin, by well trajectory



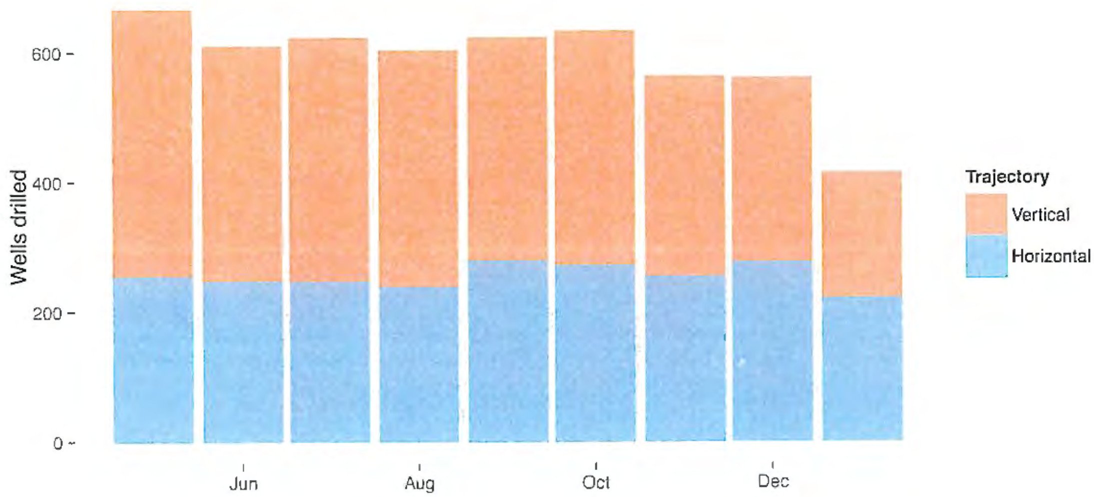
Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Figure 7. New Permian Basin liquids production from wells drilled in the month indicated, by well trajectory



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 8. New Permian Basin oil wells drilled in the month indicated, by well trajectory



Source: Drillinginfo; Scaled to compensate for number of days in month.

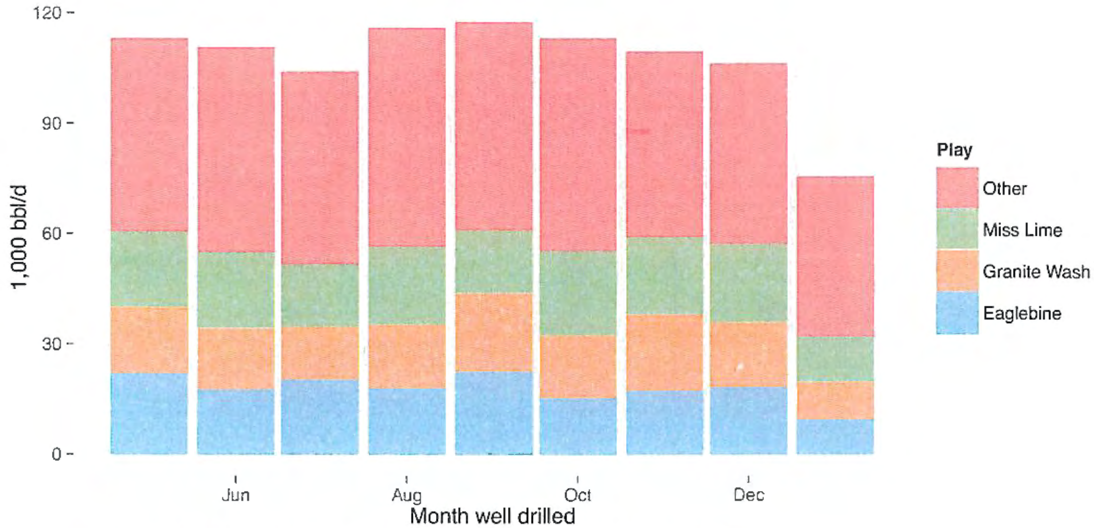
Other Areas of Onshore Oil Production

Decreases in oil production and drilling frequency are also in evidence in some smaller and lesser-known tight oil plays, as well as areas that lie outside the geographical boundaries of the major shale formations. Though the decline in activity has been sharp, these plays represent a smaller segment of upstream investment in terms of oil-directed wells (34% of national for May 2014 to January 2015), rig counts (44% of national for the same time period), and predicted peak production (19% of national). Thus, the aggregate impact of investment declines here will be minor at a national level. Again, this finding is consistent with predictions that production would be maintained in core basins and acreage where high flow rates and other factors allowed for lower unit costs. Forecasts likewise suggested that drilling and production would fall in non-core areas where higher break-even prices were needed to support continued investment and extraction.

Four areas in particular underwent sharp declines in both new wells drilled and new oil production, Drillinginfo data show. Those were the Eaglebine formation in East Texas, the Mississippian Lime formation in Kansas and Oklahoma, the Granite Wash in Oklahoma and Texas, and areas denoted on the figures below by "other," which include locations outside of defined formations. Combined, these four areas saw new oil production drop by 33% between May 2014 and January 2015, with a pronounced 29% drop from 108,000 bbl/d in December to just under 77,000 bbl/d in January.

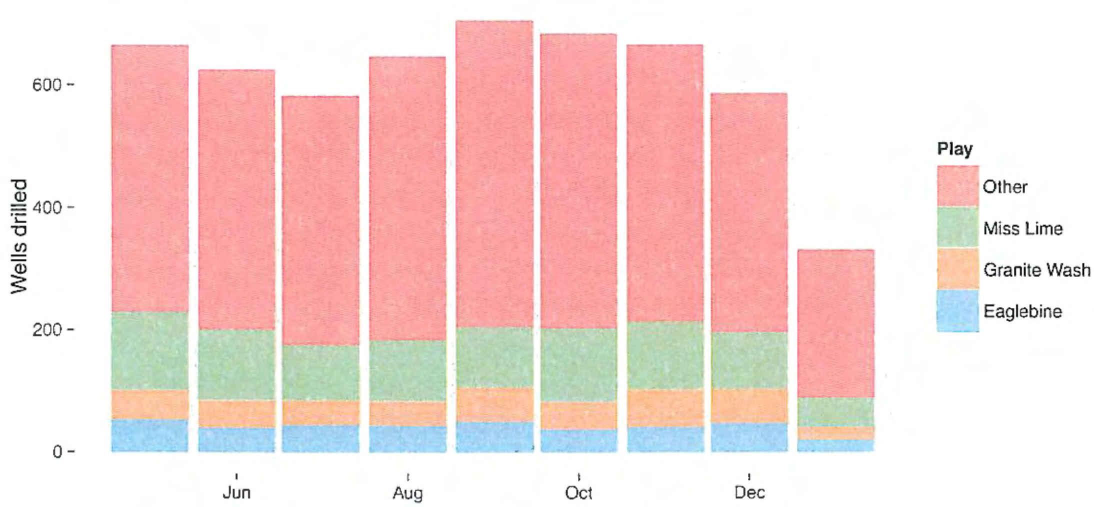
Slipping new production coincides with a declining well count. The number of oil-directed wells drilled in these four areas shrank from 676 in May to 336 in January, which includes a 44% drop between December and January.

Figure 9. New liquids production in smaller plays from wells drilled in the month indicated, by play



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 10. New oil wells in minor plays drilled in the month indicated, by play



Source: Drillinginfo; Scaled to compensate for number of days in month.

The Bakken Formation

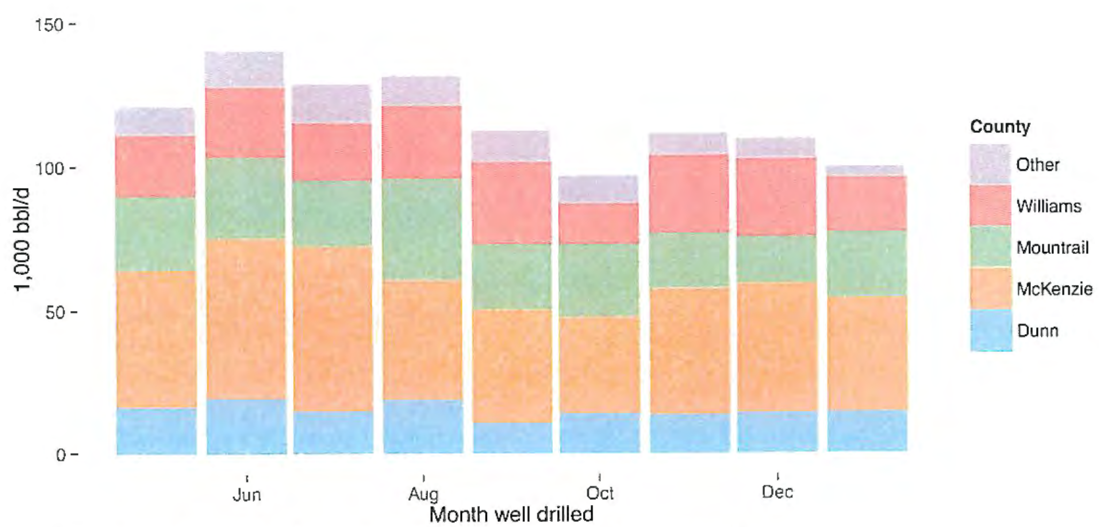
The story in the Bakken Formation, concentrated in North Dakota and spilling into Montana and southern Saskatchewan, is more equivocal. Data from Drillinginfo show predicted production dropping by 18% from around 123,000 bbl/d in May to around 101,000 bbl/d in January. However, new oil production brought onstream actually crept upward in November and then slipped modestly afterward.

Similarly, total wells drilled in the Bakken declined from 215 in May to 185 in January, with the largest drop (-122) occurring in April 2014. This period comes well before falling oil prices began to sour the investment climate in the oil patch. Declines in drilling and new production have been more modest since November.

Baker Hughes' rig count data show a less dramatic drop in oil-directed rigs operating in the Bakken during most of 2014, with numbers holding steady at just under 200 and then dropping from 190 (November 26) to 146 on January 30 after the November 27 OPEC decision.

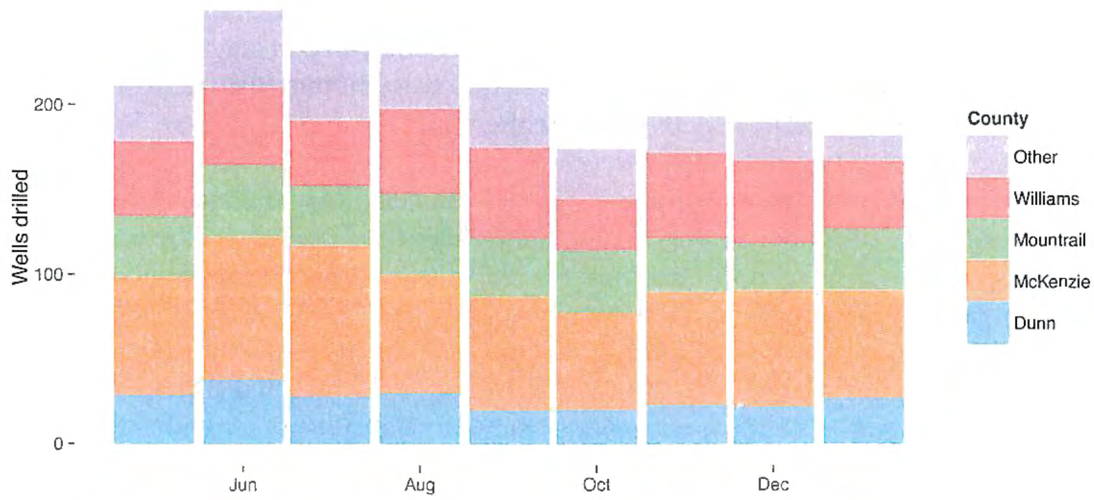
The North Dakota Department of Mineral Resources' January report also describes an atmosphere of continuing decreases in the number of operating rigs and well completions, which fell from 145 in October to an estimated 39 in November. "Oil price is by far the biggest driver behind the slowdown," the report states. "Operators report postponing completion work to avoid high initial oil production at very low prices ..."[7]

Figure 11. New Bakken liquids production from wells drilled in the month indicated, by county



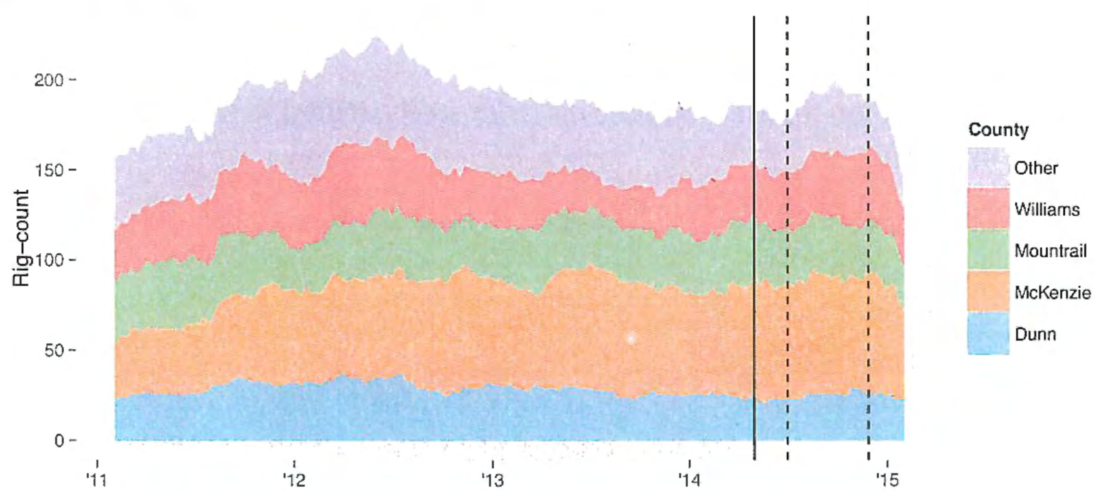
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 12. New Bakken oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 13. All active rigs in the Bakken, by county

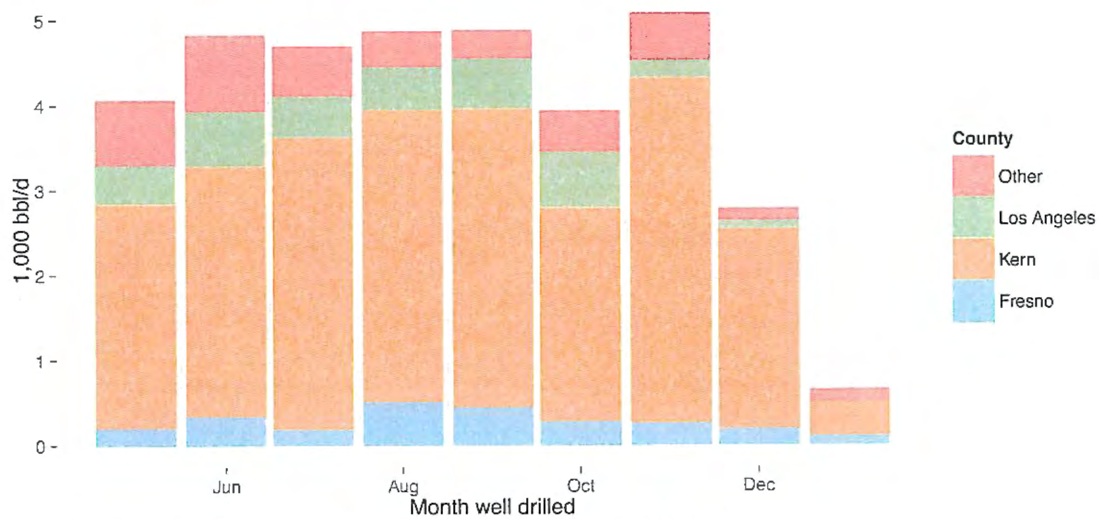


Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

California Heavy Oil

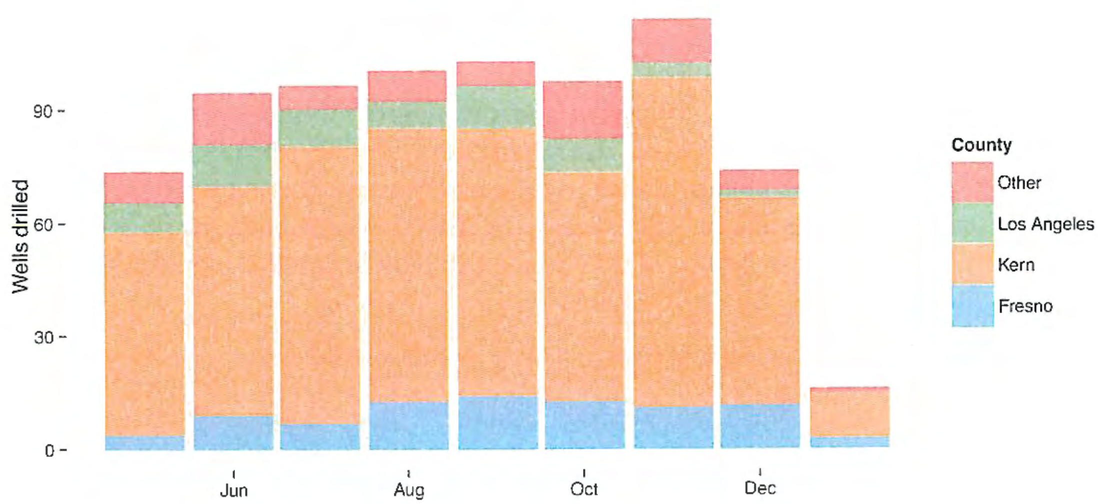
Outside of U.S. shale plays, another casualty of declining oil prices emerged in the heavy oil operation in and around Kern County and Bakersfield, California. Drillinginfo data show that new production in Kern County fell from just under 2,700 bbl/d in May to 400 bbl/d by January. The biggest monthly declines occurred in December (40%) and January (another 83%). New heavy oil production in Fresno County, never large, also slowed significantly, while that of Los Angeles County producers tracked by the company appears to have stopped altogether. Drillinginfo's production data parallels a similar decline in the number of wells drilled, which fell to 16 in January from 113 in November; Baker Hughes' data reveal a similar idling of rigs in the California heavy oil patch (see Figure 16). Besides halting production, plunging global oil prices also lie behind a financial crisis in Kern County, which declared a fiscal emergency in January.[8] The national impact of this decline will be relatively minor. Total new oil production brought onstream in a given month is over 500,000 bbl/d for the nation, but California's share tops out less than 1% of this.

Figure 14. New California liquids production from wells drilled in the month indicated, by county



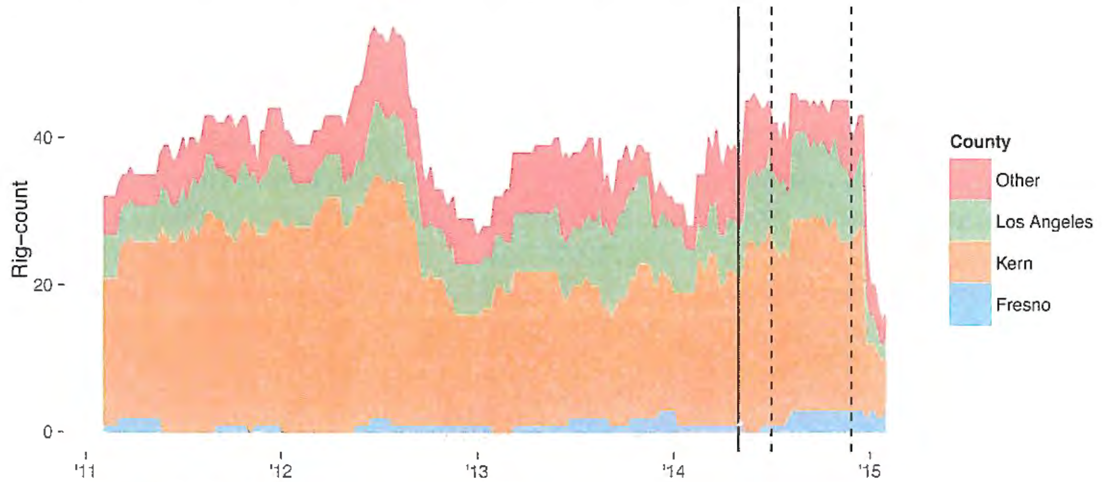
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 15. New California oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 16. Active oil-directed California rigs, by county



Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

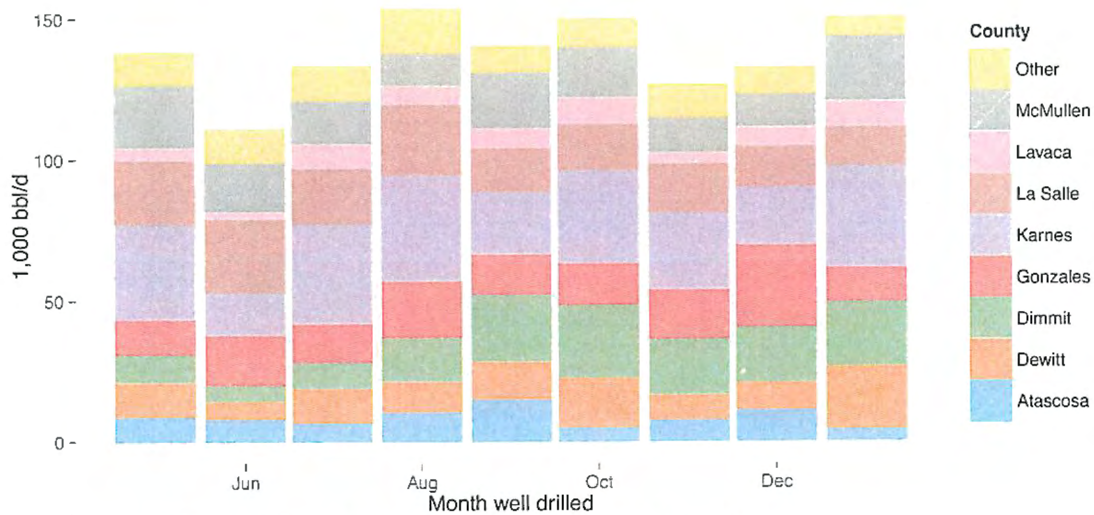
Two Places Where Production is Flat or Rising

As mentioned above, the declining new production in some areas contrasts with flat or increasing output from other formations. In addition to western areas of the Permian Basin, regions managing to resist the downward pressure include the Eagle Ford and Niobrara formations.

Eagle Ford Formation

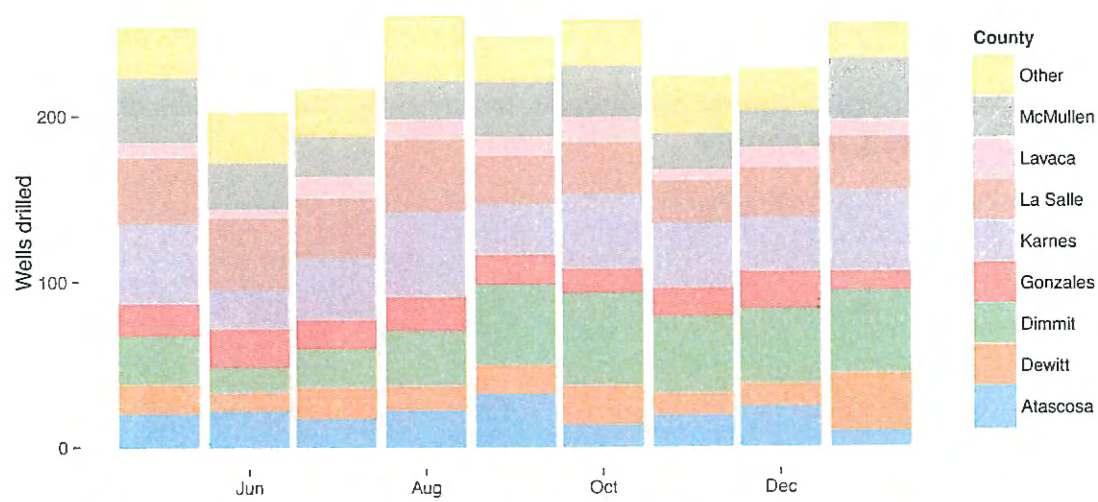
The Eagle Ford shale of South Texas was always advantaged by its close proximity to transport infrastructure and demand centers, including the Gulf Coast refinery sector. Drillinginfo predicts that new oil production actually increased in the formation, surging even during the worst hit months of December and January, when other regions were beginning to pare back. New oil wells[9] in the Eagle Ford jumped from 220 in November to 260 in January, while predicted production from these wells rose from about 133,000 bbl/d in November to about 159,000 bbl/d in January. It was unclear from the data whether this increase was a reaction to price signals or a more random event in a basin where new monthly production has risen and fallen over the short term, while remaining roughly constant since May.[10] Baker Hughes' rig data show a contrasting picture, with oil-directed rigs in operation declining immediately after the OPEC meeting in late November, from a 2014 high of 214 to 161 by January 30.[11] Rig departures could be a sign of a coming decline in oil production in the Eagle Ford.

Figure 17. New Eagle Ford liquids production from oil wells drilled in the month indicated, by county



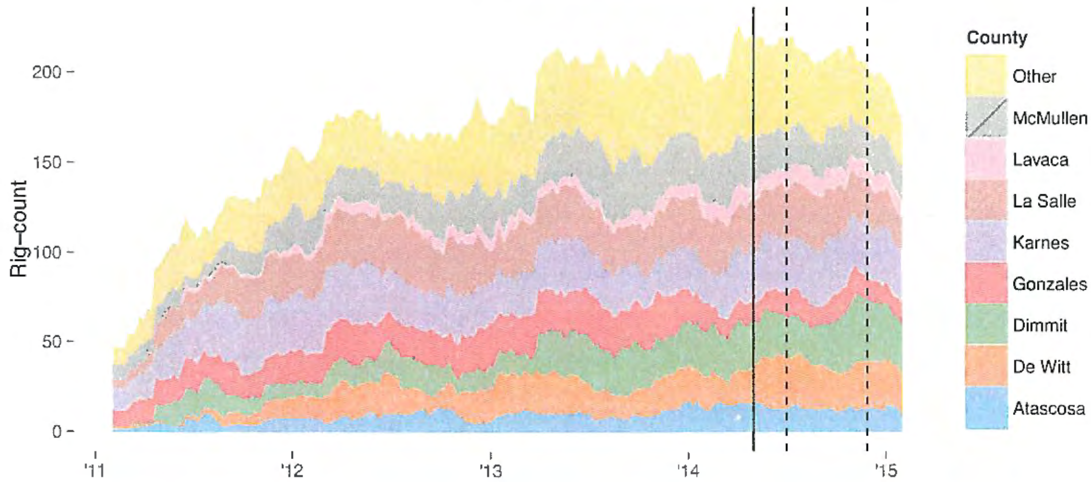
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 18. New Eagle Ford oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 19. Active oil-directed rigs in the Eagle Ford, by county

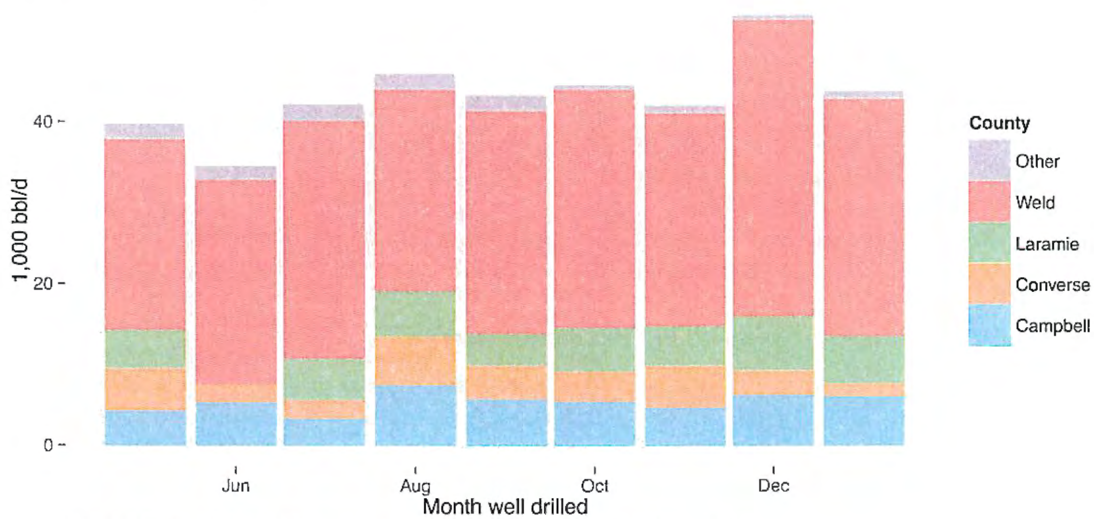


Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Niobrara Formation

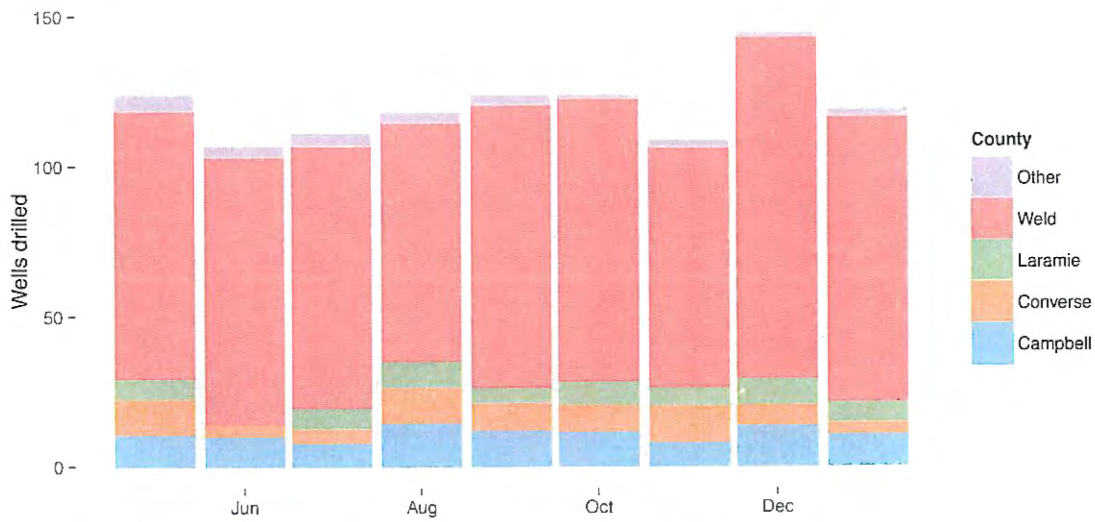
In Colorado's Niobrara chalk formation, predicted production and drilling frequency have remained relatively constant since May, including during the November-to-January period of steep declines in the oil price. Most of the activity in what Drillinginfo defines as the Niobrara has taken place in Weld County, northeast of Denver.

Figure 20. New Niobrara liquids production from horizontal oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 21. New Niobrara horizontal oil wells drilled in the month indicated, by county



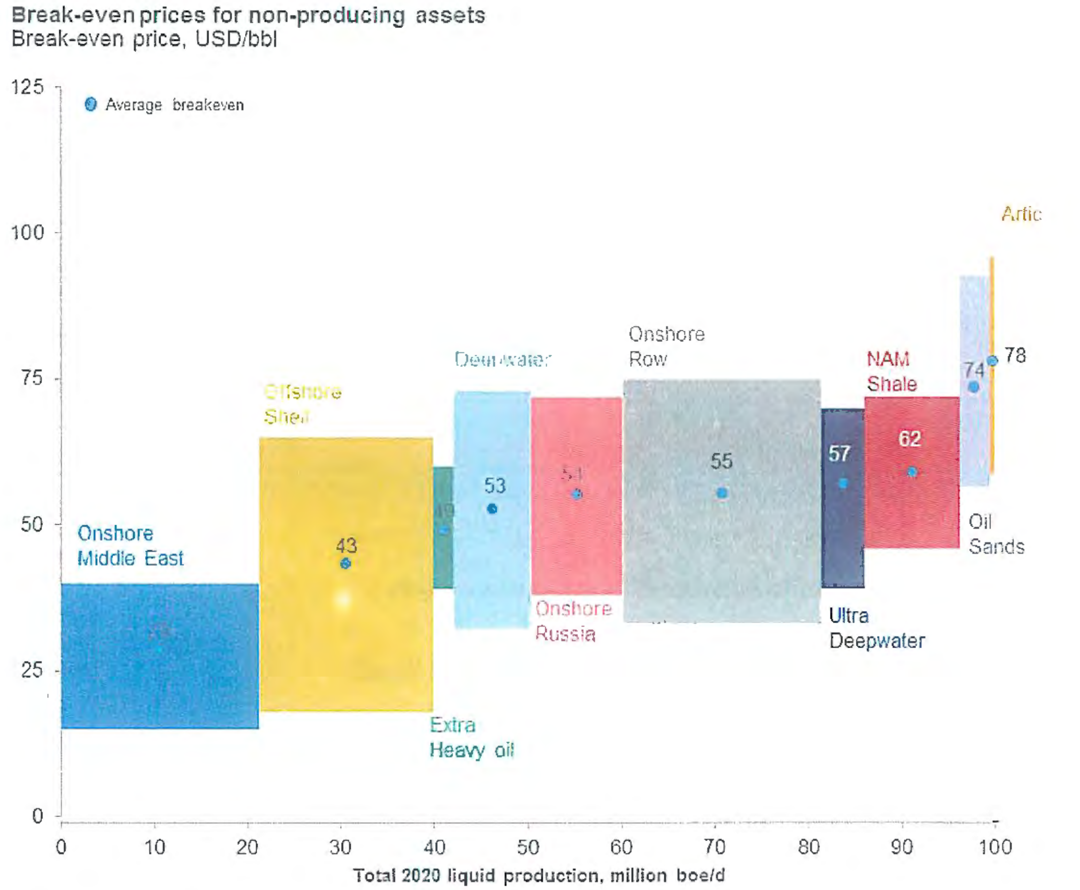
Source: Drillinginfo; Scaled to compensate for number of days in month.

Economics Behind Production Variations in U.S. Shale

There are solid economic reasons why North American light tight oil (LTO) is well suited to become a new source of "swing supply" in the global oil market. However, economic rationale also provides reasons why decreases in production might not be as rapid as one might expect, particularly in the most prolific areas.

LTO is relatively high-cost in comparison to most conventional global oil production, as shown in the plot below.[11] Standard economic theory predicts that when prices decline, the high-cost suppliers of a good or service are the first to halt production as price dips below their cost.

Figure 22. Global oil supply curve



Source: Rystad Energy

In the short-run, shale oil production should be able to respond in a much more elastic manner to price changes than large, conventional projects. These typically require years of planning and irreversible capital expenditures. Once these fixed costs are sunk, the firm's interests are best served by proceeding with production. For example, oil sands production in Canada, typically more expensive than LTO on a per-barrel basis, is less responsive to price fluctuations once investment costs are sunk.

Similarly, big startup investments may be accompanied by large shutdown costs, such as in deepwater offshore production. In these cases financial models typically require steady production volumes for many years, and often take into consideration short-term price volatility. By contrast, LTO investments are smaller and faster to execute. Low barriers to entry allowed small, independent producers to rapidly move into the market and start drilling. The same low barriers allow them to exit quickly if investing becomes unprofitable. Finally, shale wells are also characterized by steep decline curves. Hydrocarbons flow at high initial rates but tail off rapidly. Thus, revenues are earned within a much shorter time frame. This means the profitability of a project is more dependent on favorable current prices. Steep decline rates also mean that any halt to drilling implies a fast drop-off in production. In contrast, conventional wells tend to decline much more slowly, so a halt in conventional drilling takes much longer to show up in reduced production volumes.

There are also economic reasons why LTO production may respond more slowly than expected.

Markets for oilfield services and land are both very competitive, with costs dropping as producers drill fewer wells. This is particularly true in "gold rush" areas where supply of these inputs during the boom was constrained and prices were bid up. With lower costs, some producers may still be profitable and stay in business despite lower oil prices. Also, some firms have hedged production or sold volumes in forward markets, which insulates them against price drops and requires that they keep drilling to fulfill these commitments. Likewise, some producers may have already executed procurement plans for upcoming investments. If they have already paid for work (or it is costly to cancel the contracts), it may be most profitable to keep drilling.

Lease terms, which typically specify limited periods for initial drilling, provide another incentive to produce irrespective of price. However, once hydrocarbons are discovered in commercially viable quantities, mineral rights typically become "held by production" in perpetuity. The firm can return at a later date to drill additional wells once prices rise. Signs of such behavior include an increase in average rig transit time between wells as firms focus less on maximizing production and more on holding onto leases.

Finally, wells drilled in different regions of a formation may produce different quantities of oil. Wells in "sweet spots" might be profitable in a low price environment, while wells in less prolific areas are not. We should expect firms to cut their most profitable projects last. Since these "sweet spots" generally produce the highest volumes of oil, the fall in production should be smaller than the fall in the number of wells drilled. In other words, as prices drop average productivity per well should rise.

Conclusion

The picture of U.S. oil production responding to lower prices was just beginning to clarify as this paper was written. What is depicted here is an early snapshot of an industry making initial adjustments in response to a new economic environment.

This paper synergizes a compilation of quantitative evidence from multiple sources that, taken together, suggest that U.S. oil production, and in particular, that of shale oil, will be an early responder to the large drop in oil prices that occurred in late 2014. Although the actual changes in output are modest, the implications are not. The swing producer role held by Saudi Arabia since the mid-1970s appears to be in flux. At times when the Saudis decline to adjust production in line with market signals, such as at present, that role may revert to higher-cost areas of production, including some in the United States. In fact, the swing producer role was once an American concern, overseen by the Texas Railroad Commission, which, until the rise of OPEC, maintained similar production quotas aimed at reducing oil price volatility.

This time, however, the response is not being orchestrated by a governing body but by the decentralized actions of many firms responding to price signals. In the case of shale, unique characteristics allow this to happen. These include higher costs, short lead times for investment, low barriers to entry and exit, steep production decline curves, and requirements for continuous drilling to maintain constant production.

U.S. shale will probably be unable, by itself, to assume the mantle of global swing supplier. For one thing, American crude tends to serve domestic markets; producers are prohibited by law from exporting U.S. crude oil. For another, rapid declines in some shales and in vertical drilling contrast with more gradual reductions in the most profitable plays. The Baker Hughes rig counts do show the emergence of a steep, downward trend at the end of January for a number of the big plays, but the average monthly production estimates from Drillinginfo do not. These core areas—the Bakken, the Eagle Ford, the Permian Basin, and the Niobrara—make up the lion's share of new oil production. Since the wells that are drilled will be generally more productive, production should not decline as much as investment.

Shale's price responsiveness bodes well for big conventional oil producers and projects, including those outside North America, which, due to lengthy investment-to-production timelines, cannot respond as quickly. Shale's short-term investment characteristics might also help reduce the duration of the current oil bust, in contrast with the nearly two decades of low oil prices between the mid-1980s and early 2000s, which were exacerbated by the onset of huge projects in Alaska, the North Sea, and the Gulf of Mexico that were not as responsive to oil prices.

The low barriers to entry, which allowed small companies and investors to quickly move into the shale oil business, appear to be complemented by low barriers to exit, which allow them to move away when prices reverse. If OPEC and Saudi Arabia shift away from their prior swing producer roles, the nimble characteristics of U.S. shale producers may provide global markets with alternate and useful source of spare capacity.

Endnotes

1. International Energy Agency, "Oil Market Report," Jan, 16, 2015, https://www.iea.org/oilmarketreport/omrpublic/.

2. U.S. Energy Information Administration, "Short Term Energy Outlook," Jan. 13, 2015, http://www.eia.gov/forecasts/steo/report/us_oil.cfm.

3. For example, see Daniel Yergin, "Who Will Rule the Oil Market?" *New York Times*, Jan. 23, 2015, http://www.nytimes.com/2015/01/25/opinion/sunday/what-happened-to-the-price-of-oil.html.

4. Middle East Economic Survey, "MEES Interview With Ali Naimi: 'OPEC Will Never Plan To Cut,'" Dec. 22, 2014.

5. The Drillinginfo Index excludes wells in Illinois, Indiana, Alaska, and the Gulf of Mexico.

6. Defined as wells where predicted peak gas production in mcf/d was less than 1/6th of oil production (bbl/d).

7. North Dakota Industrial Commission, Department of Mineral Resources, "Director's Cut," Jan. 14, 2015, https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2015-01-14.pdf.

8. Robin Respaut, "S&P: Kern County, Calif., Outlook Negative After Fiscal Emergency," *Reuters*, Feb. 3, 2015; James Nash, "California Oil County Declares Fiscal Emergency as Crude Tumbles," *Bloomberg News*, Jan. 28, 2015.

9. See endnote 6.

10. Well counts and production are choppy in the Eagle Ford, but rig counts appear to have much less variability. This is similar to the Bakken, where flat rig counts with choppy well counts and production appear to have more to do with changes in rig transit time between jobs as drillers move rigs between locations than changes in companies' investment plans.

11. Baker Hughes' definition of the Eagle Ford territory boundary is slightly different than that of Drillinginfo, which could account for diverging data.

12. Rystad Energy, "Global Liquids Cost Curve: Shale is Pushing Out Oil Sands and Arctic, Offshore is Still in the Race," June 12, 2014, http://www.rystadenergy.com/AboutUs/NewsCenter/PressReleases/global-liquids-cost-curve.

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